TECHNICAL REVIEW AND EVALUATION FOR
SALT RIVER PROJECT, CORONADO GENERATING STATION
SIGNIFICANT PERMIT REVISION #46236
(REVISION TO OPERATING PERMIT #30732)

I. INTRODUCTION

This Class I, Title V significant permit revision is for the operation of Salt River Project (SRP), Coronado Generating Station (CGS) located 6 miles northeast of St. Johns off U.S. Highway 191 in St. Johns, Apache County, Arizona. In accordance with a Consent Decree negotiated with the U.S. Environmental Protection Agency (EPA) to reduce emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2), SRP is proposing to upgrade the air pollution control systems at the Coronado facility. The Consent Decree also establishes lower emission limits for particulate matter (PM). This permit is a significant permit revision to Air Quality Permit #30732.

A. Company Information

Facility Name: Salt River Project, Coronado Generating Station

Mailing Address: PO Box 52025, PAB 352
Phoenix, AZ 85072-2025

Facility Location: Six miles northeast of St. Johns off U.S. Highway 191
St. Johns, AZ 85936

B. Attainment Classification (Source: 40 CFR §81.303)

SRP's Coronado Generating Station is located in an area which is in attainment status for all criteria pollutants.

II. FACILITY DESCRIPTION

A. Process Description

CGS generates electricity by the combustion of pulverized coal that heats water in boiler tubes to produce steam. This steam is then used to turn a turbine which is connected on a common shaft to a generator rotor. As the rotor in the generator is turned, it induces an electrical current in the stator windings of the generator, making electricity.

CGS currently consists of two pulverized coal fired, dry bottom steam electric generating units. The facility produces a combined electrical output of 912 gross megawatts. The operating units consist of a main power building, sulfur dioxide scrubbers and limestone handling equipment, electrostatic precipitators, process water treatment facilities, a forty-three mile railroad spur, coal and ash handling facilities, coal mixing facilities, ash disposal area, combined administration and service building, water storage reservoirs, a 330 acre evaporation pond for non-recoverable waters, mechanically induced draft cooling towers, 500-kV and 69-kV switchyards, and water supply from satellite well fields.

The Coronado Emissions Control Project (CECP) includes the addition of new low-NO_x burners (LNB) along with modifications to the furnace combustion air systems (CAS) and new wet limestone flue gas desulfurization (FGD) systems to CGS Units 1 and 2. In addition, SRP proposes to install a selective catalytic reduction (SCR) system on Unit 2. Another significant component of the project related to the Consent Decree is the addition of PM continuous emission monitoring systems (CEMS). Implementation of the CECP is summarized in Table 1

Table 1: CECP Implementation Summary

Unit	Projected Operational Date	Expected Emission Rates
1 or 2	LNB/CAS – June 1, 2009	NO_x - 0.320 lb / MMBtu
1 or 2	LNB/CAS – June 1, 2011	NO_x - 0.320 lb / MMBtu
2	SCR – June 1, 2014	NO_x - 0.080 lb / MMBtu
1 and 2	June 1, 2014	NO_x – 7,300 tons per year emission limit, 365-day rolling average
2	FGD – January 1, 2012	SO_2 – 95% control or 0.080 lb / MMBtu Filterable PM – 0.030 lb / MMBtu
1	FGD – January 1, 2013	SO_2 – 95% control or 0.080 lb / MMBtu Filterable PM – 0.030 lb / MMBtu

The changes at CGS will cause a significant net increase in emissions of carbon monoxide (CO), sulfuric acid (H_2SO_4) mist, PM, and particulate matter less than 10 microns in diameter (PM_{10}), thereby triggering the need to conduct Best Available Control Technology (BACT) review for these pollutants in accordance with Arizona Administrative Code (A.A.C.) R18-2-406.A.2.

Under the CECP, SRP will add new facilities and modify several existing facilities to reduce air emissions from the power plant. Specifically, this project will include:

- Addition of low- NO_x burners to Units 1 and 2 to reduce NO_x emissions. Coupled with the burner additions will be modifications to the furnace combustion air system on each Unit.
- Addition of an SCR to Unit 2. The SCR will further reduce NO_x emissions from Unit 2.
- Replacement of the existing Pullman Kellog wet limestone FGD systems on Unit 1 and Unit 2 with new wet limestone FGD systems to further reduce SO_2 emissions.
- Addition of PM CEMS to Units 1 and 2 to monitor PM stack emissions.
- Upgrade of the existing limestone handling system.
- Addition of a second limestone storage pile with an approximate size of 17,000 tons.

- Potential upgrade of the existing bottom ash handling systems on Units 1 and 2 to convert them from wet sluice systems to either wet or dry bottom ash extractor systems.
- Modification of Unit process components to address additional auxiliary power needs associated with the new air pollution control systems.
- Replacement of the existing common stack for Units 1 and 2 with two new stacks.
- Addition of CEMS for CO to Units 1 and 2 to monitor CO stack emissions.

III. EMISSIONS

CGS has the potential to emit (PTE) criteria air pollutants, including NO_x, CO, PM, PM_{10}, volatile organic compounds (VOC) and SO_2, in excess of 100 tons per year. The facility is classified a Major Source pursuant to Arizona Administration Code (A.A.C.) R18-2-101.64. Therefore, the plant is a major source for the purposes of the Title V program and a major stationary source for the purposes of the Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NNSR) programs.

The plant is a major source of hazardous air pollutant (HAP) emissions, with potential emissions greater than 10 tons per year for any single HAP and/or greater than 25 tons per year for total combined HAP.

Typical operating parameters of the steam generating units and the auxiliary boiler are given in Table 2. Table 3 summarizes the PTE for the facility.

Table 2: Typical Operating Parameters

Description	Units 1 and 2 Boilers	
Maximum Hourly Gross MW	456 MW per Unit	
Maximum Annual Gross MW	3,994,560 MW per Unit	
Maximum Hourly Theoretical Heat Input	4,719 MMBtu/hr per Unit	
Maximum Annual Theoretical Heat Input	41,338,440 MMBtu/yr per Unit	
Type of Fuel Used	Coal	Fuel Oil / Waste Oil
Quantity of Fuel Used/Year	1,927,200 tons of coal	360,411 / 350 barrels
Maximum Hourly Use	217 tons of coal	1,728 / 86 gallons
Higher Heating Value of Fuel (max)	10,725 Btu/lb	20,900 Btu/lb
Sulfur Content	0.7%	0.14% / 0.03%
Ash Content	25%	N/A
Density of oil (lb/gal)	N/A	6.97

Table 3: Emissions

Pollutant	Pre-Change Actual		Post-Change Actual		Excluded Emissions	Net Actual Increase[1]
	Unit #1	Unit #2	Unit #1	Unit #2	Tons per Year	Tons per Year
CO	418	410	9,435	9,435	194	17,849
PM_{10}	685	593	750	1,008	158	323
Sulfuric Acid Mist	78	73	89	347	18	267
PM	520	448	566	566	118	42
VOC	50	49	64	64	25	4
NO_x	6,903	6,399	6,039	1,510	NA	(5,754)
SO_2	6,551	5,445	3,774	3,774	NA	(4,448)

1 – Values include PM/ PM_{10} emission increases from material handling modifications. Net increases (post change minus pre-change minus excluded emissions) also include allowable growth demand (excluded emissions) per A.A.C. R18-2-101 (101).
2 – Excluded emissions are the emissions increases arising out of the demand increases over the baseline levels.
* Please refer to Significant Revision application for detailed emission calculations.

IV. BACT ANALYSIS (CO, PM/PM_{10}, Sulfuric Acid Mist)

General

The term "best available control technology" is defined in A.A.C. R18-2-101.19 as "an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101.99 (a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406.A.4 to be achievable for such source or modification."

The procedures for establishing BACT are set forth at A.A.C. R18-2-406.A.4 as "BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant. In no event shall such application of BACT result in emissions of any pollutant, which would exceed the emissions allowed by any applicable new source performance standard or national emission standard for hazardous air pollutants under Articles 9 and 11 of this Chapter. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results."

The U.S. EPA's interpretive policies relating to BACT analyses are set forth in several informal guidance documents. Most notable among these are the following:

- "Guidelines for Determining Best Available Control Technology (BACT)," December 1978.
- "Prevention of Significant Deterioration Workshop Manual," October 1980.
- "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting." Draft, October 1990.

The Department generally uses what is termed a "top-down" procedure when making BACT determinations. This procedure is designed to ensure that each determination is made consistent with the two core criteria for BACT: consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions. The framework for the top-down BACT analysis procedure used by the Department comprises five key steps as follows:

1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The five-step procedure mirrors the analytical framework set forth in the draft 1990 guidance document. However, it should be noted that the Department does not necessarily adhere to the prescriptive process described in the draft 1990 guidance document. Strict adherence to the detailed top-down BACT analysis process described in that draft document would unnecessarily restrict the Department's judgment and discretion in weighing various factors before making case-by-case BACT determinations. Rather, as outlined in the 1978 and 1980 guidance documents, the Department has broad flexibility in applying its judgment and discretion in making these determinations.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
- Information provided by pollution control equipment vendors.
- Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/LAER Clearinghouse.

It is important to note that the increase in PM/PM_{10}, CO, and sulfuric acid mist emissions is a direct result of the implementation of other air pollution control devices intended to significantly reduce the amount of NO_x and SO_2 emissions, 5,754 tons per year and 4,448 tons per year respectively, generated by this facility. As a result of the reduced emissions of these primary pollutants, these pollutants are not subject to the same level of review as those pollutants experiencing a significant emissions increase CO, PM_{10}, PM, and sulfuric acid mist emissions (17,849, 323, 42, and 267 tons per year respectively).

The BACT evaluations and proposed BACT determinations for CO, PM/PM_{10}, and sulfuric acid mist emissions associated with the low NO_x burner retrofits, installation of SCR on Unit 2 and installation of the new FGD systems at the CGS facility are discussed in the following subsections.

BACT for CO Emissions

<u>Step 1 – Identify All Available Control Technologies</u>

Available control technologies for CO emissions from the pulverized coal-fired boilers include good combustion practices, oxidation catalysts, and thermal oxidation.

<u>Step 2 – Eliminate All Technically Infeasible Control Technologies</u>

Coal-fired boilers have several characteristics that make the use of oxidation catalysts technically infeasible, including low excess oxygen levels in the flue gas, low flue gas temperatures, and catalyst fouling/poisoning by fuel sulfur and fly ash. Because of these technical problems, oxidation catalysts have not been used to reduce CO emissions from coal-fired boilers.

Thermal oxidation would involve injecting additional air into the flue gas and heating the oxygen enriched mixture to approximately 1,500°F to oxidize CO to carbon dioxide. However, since the combustion of the reheat fuel would also result in CO emissions, there is no evidence that thermal oxidation would result in any CO emission reductions. Since thermal oxidation has never been demonstrated on a coal-fired boiler, and because there is no evidence that it could reduce CO emissions, thermal oxidation is not considered by the Department to be a technically feasible CO control technology for coal-fired boilers.

<u>Step 3 – Rank Control Effectiveness of Technically Feasible Control Options</u>

Based on the above analysis, good combustion practices (GCP) is the only technically feasible CO control technology for pulverized coal-fired boilers. GCP or combustion controls generally include the following components:

- Good air/fuel mixing in the combustion zone;
- High temperatures and low oxygen levels in the primary combustion zone;
- Overall excess oxygen levels high enough to complete combustion while maximizing boiler thermal efficiency; and
- Sufficient residence time to complete combustion.

RBLC Data indicate that the recent CO BACT emission limits using GCP for new utility steam boilers have been approximately 0.15 lb/MMBtu. Emission limits for modified boilers ranges from 0.15 lb/MMBtu to 1.63 lbs/MMBtu. Of the listings for modified units, three are retrofitted with low NO_x burners, similar to the modifications proposed for the GCS units (all

Detroit Edison units located at two separate facilities). No emission limits were specified for these units.

The CGS units will be retrofitted with low NO_x burners and over-fire air systems. Because these boilers will be retrofitted rather than being originally designed for optimum combustion as with new units, it is uncertain whether the retrofitted units can achieve the same CO emission rates as new boilers. Therefore, rather than setting the CO emission rates equal to the lowest proposed BACT limits for new units in the RBLC, CGS has proposed an achievable rate of 0.50 lb/MMBtu, based on a daily rolling 30-day average, a median RBLC value that has been demonstrated in practice. In addition, CGS has also presumed a CO maximum hourly rate of 3.6 lb/MMBtu for short-term dispersion modeling purposes.

CO emissions from pulverized coal-fired boilers can spike during periods of startup, shutdown, or malfunction because of unstable combustion conditions. CO (and volatile organic compound) emissions are also sensitive to boiler operating conditions. Changes in operating conditions, such as coal mill (pulverizer) starts and stops, can have a significant, though temporary, impact on CO emissions. This condition is further exasperated during boiler startup because the boiler itself is relatively cool, and the low air flow rates make it difficult to obtain good air/fuel mixing. CGS has proposed to exclude time periods of startup, shutdown, and malfunction from the BACT limit and shall not emit more than 3.6 lb/MMBtu CO during such startup and shutdown periods.

Step 4 – Evaluate the Most Effective Controls

Because no specific CO control technologies or practices beyond good combustion practices were identified as part of this BACT analysis, additional evaluation is unnecessary.

Step 5 – Select BACT for CO Emissions

Based on this analysis, it can be concluded that the use of good combustion practices is the best available control technology for CO emissions for the CGS Units 1 and 2 low-NO_x burner retrofit project. This control technology can achieve a CO emission rate of 0.50 lb/MMBtu based on a 30-day rolling average and an hourly rate of 3.6 lb/MMBtu to address fluctuations during startup and shutdown periods. The Department concurs that the proposed emission limits represent BACT for CO emissions from pulverized coal-fired boilers at the CGS facility. In addition, by December 31, 2010, SRP will be required to provide a demonstration to the Department of whether a lower CO emission limit can be achieved based on actual operation of the modified boilers.

BACT for PM/PM_{10} Emissions

Step 1 – Identify All Available Control Technologies

CGS has identified two technologies for control of PM/PM_{10} from Unit 1 and 2:

- Existing HS-ESP; and
- Replacing the existing HS-ESP with a Fabric Filter.

Step 2 – Eliminate All Technically Infeasible Control Technologies

The facility currently uses ESPs for controlling particulate matter. Therefore, use of the existing ESPs is considered technically feasible. Fabric filtration has been widely applied for controlling particulate emissions from coal combustion facilities, and is also considered technically feasible.

Step 3 – Rank Control Effectiveness of Technically Feasible Control Options

ESPs are most efficient when collecting larger particles, as larger particles have a higher mass-to-surface-area ratio, allowing the larger particles to be collected more efficiently on the charged plate. Finer particles do not carry strong enough electrical charges and are therefore, much less efficiently collected.

Fabric filtration is highly efficient in collecting both large and small particles; as a result the fabric filter was determined to be more efficient for collecting PM_{10} emissions than an ESP.

Step 4 – Evaluate the Most Effective Controls

When considering the environmental impacts of any pollution control device, it is important to note that all the increases in CO, PM/PM_{10}, and sulfuric acid mist allowed by this permit are a direct result of the installation of other pollution control that will achieve significant reduction in NO_x and SO_2 emissions from the facility. The additional PM_{10} and PM emissions associated with the installation of the NO_x and SO_2 is generally expected to occur as a result of the formation of ammonium nitrate and ammonium sulfates. Neither of these is expected to be formed during the combustion of coal, or while the exhaust gases are traveling through SRP's Electrical Generating Station. Instead these pollutants are expected to form in the atmosphere through secondary chemical interactions associated with increase ammonia and sulfuric acid emissions.

The facility currently uses ESPs for controlling particulate matter. The ESPs are designed to control PM and PM_{10} emissions that result from combustion of coal. The proposed project will not result in a decrease in the efficiency of the ESPs collection of PM and PM_{10} emissions. In addition no adverse environmental, energy, economic or other impacts are expected to be associated with the continued use of the existing ESPs.

As part of the application for this permit revision, SRP considered replacing the ESPs with fabric filtration. Replacing the existing ESPs with fabric filters would ultimately result in an energy savings for the company. From an environmental perspective, installing fabric filter units would also result in collection of additional PM and PM_{10} formed during combustion of the coal. Installation of the fabric filtration units, however, would have little or no impact on the secondary formation of PM and PM_{10} associated with this project. The visibility benefits associated with the additional control of NO_x and SO_2 emissions are greater than the visibility impairment associated with the additional emissions of PM and PM_{10} associated with this project. Economically, installation of the fabric filtration system would result in large capital cost and significant operating expenses in the form of maintenance and routine replacement of fabric filters. As a result, the incremental cost effectiveness of removing the additional PM_{10} was found to be more than $21,000 per ton of PM_{10} reduced.

Step 5 – Select BACT for PM/PM_{10} Emissions

After considering all of the available control technologies, eliminating the technically infeasible controls, ranking the control effectiveness of the technically feasible control options, and evaluating the most effective controls based upon environmental, energy, economic, and other impacts, the Department has determined that BACT for PM/PM_{10} for CGS Units 1 and 2 is the continued use of the ESPs. The Department has determined that this control technology is capable of achieving a filterable PM/PM_{10} emission rate of 0.30 lb/MMBtu based upon 3-hour average, and concurs that this emission limitation achieves BACT from the pulverized coal-fired boilers at the CGS facility.

BACT for Sulfuric Acid Mist (SAM) Emissions

Step 1 – Identify All Available Control Technologies

Available control technologies identified for sulfuric acid mist emissions from the pulverized coal-fired boilers include:

- Fuel switching;
- Fuel washing;
- Fuel processing;
- Sorbent Injection Systems;
  - Ammonia Injection
  - Sodium-Based Sorbent Injection
  - Humidification
  - Hydrated Lime Injection System
- Sorbent Injection with Polishing Fabric Filter Baghouse;
- Dry Flue Gas Desulfurization Control Systems;
- Co-benefit SAM Capture in the Existing HS-ESP/Wet flue gas desulfurization (WFGD);
- Replace Existing HS-ESP with Fabric Filter Baghouse;
- Low-Activity SCR Catalyst; and
- Wet Electrostatic Precipitation.

Step 2 – Eliminate All Technically Infeasible Control Technologies

The available various control technologies are discussed in brief for checking their feasibility for control of SAM.

- Fuel Switching: Switching to a lower sulfur coal can be one option for reducing emission of SO_2/SO_3. CGS currently fires a blend of western bituminous coal and PRB subbituminous coal as its primary fuel. Western bituminous coal has sulfur concentrations ranging from 1.0 to 1.5% with a heating value range of 9,200 to 12,000 British thermal unit (Btu) per pound. PRB coal has sulfur concentrations below 1.0% with a heating value range of 8,000 to 8,600 Btu per pound. Switching to 100% PRB subbituminous coal could potentially reduce boiler SO_3 emissions. Further, due to lower heating value of PRB coal, the quantity of coal required at the CGS will also go up by at least 15 to 39%. The reliability of PRB deliveries and the continued availability of low-sulfur PRB coal is a legitimate and significant concern. In order to minimize potential issues associated with dependable fuel delivery and to ensure economical long-term supply of fuel, CGS must keep the option to use western bituminous coals. Thus switching to 100% PRB subbituminous coal is not considered an available SAM control option.

- Fuel Washing: Coal washing, or beneficiation, is one pre-combustion method that has been used to reduce impurities in the coal such as ash and sulfur. In general coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. While with washing of fuel, rocks including sulfur bearing pyrites are removed, a significant amount of coal is also lost. Further the fuel washing has to occur at the pit head. To date, no coal washing plants have been built to wash western coals. Therefore, requiring washed coal as a strategy to reduce SO_3 emissions is not considered an available SAM control option.

- Fuel Processing: Pre-combustion coal processing techniques have been proposed as one strategy to reduce the sulfur content of coal and help reduce uncontrolled SO_2 and SO_3 emissions. So far the use of processed fuel has been demonstrated with test burns in a coal–fired boiler only. This has not been tried as a primary fuel in an on-going, long term basis. Moreover it does not appear that an adequate supply of processed fuel would be available for commercial long-term basis. In view of this, processed fuel is not considered a technically feasible or commercially available SAM control option.

- Sorbent Injection Systems:

  - Ammonia Injection: Ammonia based systems designed for sulfuric acid control typically involves injection of ammonia into the flue gas upstream of a cold- side electrostatic precipitator (CS-ESP). Ammonia reacts with SO_3 in the flue gas to form ammonia salts, mainly ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4]. Formation of ammonia salt is dependent on the temperature of flue gas and stoichiometric ratios. In the case of CS-ESP, flue gas temperature is in the range of 300 to 350^0F which favors formation of NH_4HSO_4 whereas in the case of HS-ESP, flue gas temperature is in the range of 650^0 to 750^0F which favors formation of $(NH_4)_2SO_{4.}$ NH_4HSO_4 tends to make fly ash more cohesive, which promotes fly ash capture in a CS-ESP. $(NH_4)_2SO_4$ is a sticky substance that can adhere to duct walls and downstream equipment and cause significant plugging and blockage issues. Since CGS has HS-ESP, ammonia injection is not considered a technically feasible SAM control option.

  - Sodium based Sorbent Injection: This has been studied as a SAM reduction control strategy. Sodium-based sorbents can be injected directly into the flue gas to react with $SO_3/H_2SO_{4.}$ This type of sorbent has been demonstrated on units equipped with CS-ESP and fabric filter baghouses. These have not been demonstrated on units equipped with WFGD. Sodium-based injection systems have not been demonstrated on coal-fired units equipped with HS-ESP control arrangements. Therefore, it is concluded that sodium-based injection systems is not technically feasible for SAM control option.

  - Humidification: Humidification adds water upstream of the WFGD to slowly cool the flue gas below its acid dew point and thereby condense large acid droplets. The WFGD more effectively captures larger acid droplets. However, humidification upstream of the WFGD may cause fly ash dropout in the ductwork resulting in corrosion or choking of equipment near the WFGD inlet. This process has not been demonstrated on coal-fired boilers equipped with WFGD. Therefore, humidification is not considered a technically feasible SAM control option.

- Dry Flue Gas Desulfurization Control System: Dry scrubbing has been designed to remove SO_2 from flue gases. This involves introduction of dry lime or hydrated lime slurry into a reaction tower where lime reacts with SO_2 to form calcium sulfite solids. This dry by-product should be removed with the fly ash in the PM control equipment.

On existing units equipped with a HS-ESP particulate control system, retrofitting the unit with dry FGD includes not only the dry FGD control system but replacing the HS-ESP with a fabric filter baghouse. Dry scrubbing is not an available SAM BACT control option for following reasons:

- Installing a dry scrubbing system would require a complete redesign of the unit's air pollution control system;
- Existing HS-ESP and WFGD control system will have to be replaced with dry FGD and fabric filter (FF) baghouse controls;
- Dry scrubbing systems are not as effective at SO_2 removal; and
- Replacing the WFGD system with a dry scrubbing system would likely result in an increase in SO_2 emissions.

Considering the above, dry scrubbing system is not considered a technically feasible option for control of SAM at CGS.

<u>Step 3 – Rank Control Effectiveness of Technically Feasible Control Options</u>

The available various control technologies are discussed in brief for checking the control effectiveness for SAM.

- Wet FGD + Wet ESP: WESP have been proposed to control SAM emissions from boilers firing a high-sulfur bituminous coal and equipped with SCR and WFGD. This combination of coal and control equipment results in a relatively high concentration of sulfuric acid in the flue gas. The lower sulfur coals fired at CGS generate SAM emissions that are essentially equal to the controlled emissions achieved with WESP on high sulfur applications. Thus WESP control system would be technically feasible SAM control option for Unit 2. WESP would be located downstream of the unit's WFGD system. It is very likely that the WESP would reduce the emission of SAM but presently there is no concrete data to support this. Based on engineering judgment, it is anticipated that the WESP would reduce the emission of SAM by 75%.

- Sorbent Injection followed by Polishing Fabric Filter: Sorbent injection for SAM control will increase particulate loading to the WFGD control system and will likely result in increased emissions of PM. A control option to address the increased particulate loading to the WFGD will be to install a fabric filter baghouse between the sorbent injection and the WFGD. The Compact Hybrid Particulate Collector (COHPAC) is an EPRI-patented concept that combines sorbent injection with a high air-to-cloth ratio baghouse. Here dry sorbent is injected upstream of the COHPAC baghouse to enhance SAM removal and reduce the particulate loading to the WFGD. Similar systems have been installed on coal-fired boilers for mercury control, and can be used for SAM control at CGS. Based on engineering judgment, it is anticipated that a sorbent injection system followed by COHPAC baghouse can reduce SAM emissions by 75%.

- Replacing the Existing HS-ESP with a Fabric Filter Baghouse (FF): It has been seen that the high flue gas temperature in the case of HS-ESP is not good for capturing H_2SO_4 since higher flue gas temperature limits the quantity of H_2SO_4 that will condense on the fly ash particles to be removed in the ESP. Particulate control devices located downstream of the air heater are generally more effective at removing H_2SO_4

mist. FF located downstream of the air heater have demonstrated the ability to capture acid mist emissions. SO_3, being very reactive, readily reacts with alkaline components of the fly ash at temperatures below the H_2SO_4 dew point to form sulfate salts. Fly ash cake that accumulates on the filter bags acts as an alkaline filter through which flue gas must pass. The SO_3 removal efficiency of a FF is dependent on the flue gas temperature and alkalinity of the fly ash cake. Flue gas temperature at the FF inlet is typically in the range of 300^0F, which is above the acid dew point of 270^0F. Flue gas temperature is maintained above the dew point to avoid the acid condensation which may cause corrosion, plugging, and adverse impacts on the FF life. Based on the ash characteristics of western bituminous and subbituminous coals and the expected flue gas temperature around 300^0F, overall SAM removal across a FF will be in the range of 50%. Further it can be assumed that the WFGD downstream of the FF would recover another 20%, cumulative SAM reduction would be approximately 44%.

- Hydrated Lime Sorbent Injection: Hydrated lime control system involve the injection of hydrated lime [$Ca(OH)_2$] into the flue gas ductwork downstream of the air heater. Hydrated lime will react with both vapor and condensed H_2SO_4 to form calcium sulfate that can be removed by the WFGD. Hydrated lime has a high surface area per unit volume to promote reaction with H_2SO_4. Data from full-scale tests on coal-fired units suggest that a hydrated lime injection rate based on a 4:1 stoichiometric ratio (Ca: SO_3) would be required for effective SAM control. Actual injection rates would vary depending on the H_2SO_4 concentration in the flue gas and may be limited by increased particulate loading to the WFGD. It is expected that the hydrated lime injection at the above ratio will increase SAM capture in the WFGD from 20% to 50%. Assuming 50% removal in the WFGD, SAM emissions from Unit 2 will be reduced by approximately 39%.

- Fuel Additives or Sorbent Injection to Boiler: SO_3 generated in the boiler will react with the alkaline components in the fly ash forming sulfates. Sulfates generated in the boiler can be captured in the unit's HS-ESP. One method of increasing fly ash alkalinity, and enhancing SO_3 removal in the HS-ESP, is to add alkaline additives directly to the coal. Various calcium, magnesium, sodium, and potassium-based materials have been studied for SO_3 capture. Potentially available sorbent materials include lime, limestone, magnesium carbonate, etc. Based on engineering judgment, magnesium-based sorbent material would be most appropriate for use at CGS and is expected that alkaline fuel additive would reduce SO_2 to SO_3 conversion in the boiler from 0.5% (assumed for the base case) to 0.35%, reducing overall SAM emissions from the boiler. Using magnesium –based sorbents for SO_3 capture has the following potential drawbacks. First the stoichiometric rations required for SO_3 capture can be as high as 30 to 40:1. Second, when added to coal, alkaline additives may also modify the slagging and fouling tendencies of the coal ash and in some cases have produced unacceptable increases in slagging, increase loss on ignition (LOI), and increase furnace exit temperatures. Third, reducing flue gas SO_3 at the HS-ESP inlet may increase fly ash resistivity, reducing the effectiveness of the HS-ESP. Finally, sorbents added to the coal will only capture furnace generated SO_3, and are not effective at capturing SCR-generated SO_3.

  Another option for increasing SO_3 capture in the HS-ESP is to inject alkaline compounds directly into the furnace. SO_3 generated in the boiler will react with the alkaline components in the furnace forming sulfate compounds that can be captured in the unit's HS-ESP. As with fuel additives, sorbent injection in the furnace will reduce furnace generated SO_3 but will be less effective at reducing SO_3 emissions resulting from SCR oxidation. Based on engineering judgment, it is expected that alkaline fuel additives would mitigate a portion of the SO_2 that is converted to SO_3 in the boiler by approximately 30%, from 0.5% (assumed for the base case) to 0.35%, reducing overall SAM emissions from the boiler. Reducing SO_2 to SO_3 conversion in the boiler will reduce overall H_2SO_4 emissions from Unit 2 by 11%. Limited overall SAM removal is achieved with the fuel additive and furnace injection control strategies because they provide little control of SO_3 formed in the SCR.

- Co-Benefit Capture in Existing HS-ESP/WFGD and Low-Activity SCR Catalyst: SO_3 generated during the combustion process will ultimately react with available moisture to form sulfuric acid. Depending on the temperature of the flue gas, the H_2SO_4 will either be in the vapor phase or liquid phase. Air pollution control technologies designed to capture particulate matter and SO_2 may also capture SO_3 and H_2SO_4, and reduce SAM emissions. SAM removal efficiencies in existing air pollution control systems will depend on the flue gas temperature, composition, and acid concentration. This existing configuration was selected as the baseline for comparison of the identified controls.

Table 4 lists the expected annual SAM emissions associated with each technically feasible control technology.

Table 4: SAM Emissions associated with Technically Feasible Technologies

Control Technology	Annual Emissions	Annual Reduction in Emissions	
	(tpy)	(tpy from base case)	(% from base case)
Co-benefit capture in existing HS-ESP/WFGD and low-activity SCR catalyst (baseline)	347	Baseline	Baseline
Fuel additives or sorbent injection to boiler	309	38	11
Hydrated Lime injection system	212	135	39
Replacing existing HS-ESP with fabric filter baghouse	194	153	44
Sorbent injection with polishing baghouse	87	260	75
Wet FGD + Wet Electrostatic Precipitation	87	260	75

Step 4 – Evaluate the Most Effective Controls

An economic evaluation was performed for technologies identified for further evaluation. The details of the capital costs, operating costs, and other costs are detailed in the application submitted by the Permittee. The evaluation indicated an overall cost effectiveness of the various technically feasible options and is provided in Table 5 below:

Table 5: Cost Effectiveness associated with Technically Feasible Technologies

Control Technology	Incremental Annual Cost Effectiveness beyond baseline ($/ton removed)
Co-benefit capture in existing system and low-activity SCR catalyst (baseline)	----
Hydrated Lime injection system	$2,828
Fuel additives or sorbent injection to boiler	$18,557
Sorbent injection with baghouse	$23,260
Wet FGD + wet electrostatic precipitation	$46,648
Replacing existing ESP with baghouse	$73,750

Sorbent injection systems (including hydrated lime injection) will increase particulate loading to the unit's WFGD. Increased particulate loading to the WFGD could increase PM emissions, resulting in potential compliance issues. Based on engineering calculations, it is estimated that at full load operations, particulate matter loading to WFGD will increase from approximately 141.6 lbs/hr to approximately 388 lbs/hr or 0.082 lb/MMBtu. In line with the consent decree, Unit 2 will be required to achieve a controlled PM emission limit of 0.030 lbs/MMBtu. The WFGD would have to reduce total PM loading by at least 64% to achieve 0.030 lbs/MMBtu. Factors like flue gas flow rate, operating parameters, inlet PM concentration, and particle size distribution affect the performance of WFGD. Based on the RACT data, it appears that the WFGD will reduce PM emissions by approximately 50-55% (based on an inlet loading of 0.082 lb/MMBtu). This removal efficiency results in a controlled emission rate of 0.037 lb/MMBtu. Therefore it appears unlikely that SRP could meet the specified PM emission limit with hydrated lime injection. Increased PM emissions are considered a significant collateral impact, and the inability to achieve a controlled emission of 0.030 lbs/MMBtu could result in significant compliance issues. No other potential collateral environmental impacts associated with the other control technologies were identified.

Step 5 – Select BACT for Sulfuric Acid Mist Emissions

After considering all of the available control technologies, eliminating the technically infeasible controls, ranking the control effectiveness of the technically feasible control options, and evaluating the most effective controls based upon environmental, energy, economic, and other impacts, the Department has determined that the continued use of the wet FGD and the existing ESP along with the use of a low-activity SCR catalyst is BACT for CGS Unit 2. The Department has determined that this control technology is capable of achieving a SAM emission rate of 0.018 lb/MMBtu as measured by a performance test, and concurs that this emission limitation achieves BACT from the pulverized coal-fired boilers at the CGS facility.

V. BACT FOR LIMESTONE/DRY BOTTOM ASH HANDLING SYSTEM

A. Limestone Handling System

Step 1 – Identify All Available Control Technologies

Available control technologies for PM/PM_{10} emission points from the new/modified limestone handling sources associated with the primary and alternative operating scenarios are:

- Total Enclosure;
- Capture and Collection System (Baghouse);
- Capture and Collection System (Wet Scrubber);
- Capture and Collection System (ESP);
- Capture and Collection System (Cyclone);
- Vent Bag Filter/Filter Separator;
- Wet Suppression.

Step 2 – Eliminate All Technically Infeasible Control Technologies

All the above identified technologies are technically feasible and will be considered for the BACT analysis.

Step 3 – Rank Control Effectiveness of Technically Feasible Control Options

All technically feasible options are ranked in the order of overall control effectiveness. The most effective control option is the one that achieves the lowest emissions level. The technically feasible PM/PM_{10} control technologies are listed in Table 6 in descending order of control efficiency:

Table 6: Filterable PM/PM_{10} Control Technology Emission Rate Ranking

Control Technology	% Reduction
Total Enclosure	100
Capture and Collection System (Baghouse)	99
Vent Bag Filter/Filter Separator	99
Capture and Collection System (Wet Scrubber)	98
Capture and Collection System (ESP)	95
Wet Suppression	95
Capture and Collection System (Cyclone)	90

Step 4 – Evaluate the Most Effective Controls

From Table 6, it can be seen that the most effective control is use of a total enclosure, a capture and collection system with a baghouse as the collection system, or use of a vent bag filter/filter separator. There are no adverse environmental or energy impacts associated with any of these three options.

Step 5 – Select BACT for PM/PM_{10} Emissions

SRP has proposed the use of either a total enclosure or a capture and collection system utilizing baghouse as a BACT for filterable PM/PM_{10} on the new/modified limestone handling system emission points associated with the primary and alternate operating scenarios with a BACT limitation for filterable PM/PM_{10} of 0.005 grains per actual cubic feet (gr/acf). These control options represent the most effective control technology available and the Department agrees that these represent BACT.

B. Dry Bottom Ash Handling System

Step 1 – Identify All Available Control Technologies

Available control technologies for PM/PM_{10} emission points from the alternative operating scenario for the dry bottom ash handling system are:

- Total Enclosure;
- Capture and Collection System (Baghouse);
- Capture and Collection System (Wet Scrubber);

- Capture and Collection System (ESP);
- Capture and Collection System (Cyclone);
- Vent Bag Filter/Filter Separator;
- Wet Suppression.

Step 2 – Eliminate All Technically Infeasible Control Technologies

All the above identified technologies are technically feasible and will be considered for the BACT analysis.

Step 3 – Rank Control Effectiveness of Technically Feasible Control Options

All technically feasible options are ranked in the order of overall control effectiveness. The most effective control option is the one that achieves the lowest emissions level. The technically feasible PM/PM_{10} control technologies are listed in Table 7 in descending order of control efficiency:

Table 7: Filterable PM/ PM_{10} Control Technology Emission Rate Ranking

Control Technology	% Reduction
Total Enclosure	100
Capture and Collection System (Baghouse)	99
Vent Bag Filter/Filter Separator	99
Capture and Collection System (Wet Scrubber)	98
Capture and Collection System (ESP)	95
Wet Suppression	95
Capture and Collection System (Cyclone	90

Step 4 – Evaluate the Most Effective Controls

There are no adverse environmental or energy impacts associated with any of the control options listed above. There are substantial economic impacts associated with the top four control options when the costs of the control are compared with the additional reduction in PM/PM_{10} emissions. The total increase in emissions from all material handling sources (including the limestone handling system) is only 4 tpy for

PM_{10} and 4.1 tpy for PM.

Step 5 – Select BACT for PM/PM_{10} Emissions

SRP is proposing to use either a vent bag filter/filter separator or a wet suppression system as a BACT for filterable PM/PM_{10} on the new/modified dry bottom ash handling system emission points associated with the alternate operating scenario with a BACT limitation of filterable PM/PM_{10} of 0.005 grains per actual cubic feet (gr/acf). These control options represent the most effective control technology available and the Department agrees that these represent BACT.

VI. MONITORING AND COMPLIANCE DEMONSTRATION PROCEDURES

As described in Section IV, both steam boiler units at CGS will be retrofitted with low-NO_x burners and over-fire air systems and will be subject to the CO emission limits of 0.50 lb/MMBtu on a 30-day rolling average and 3.6 lb/MMBtu on hourly basis. CGS is required in this permit action to install and operate a continuous monitoring system at each boiler stack for carbon monoxide emissions. The monitoring system will be used to demonstrate compliance with the CO emission limits and is required to meet the following:

- 40 CFR Part 60, Appendix B, Performance Specification 4, "Specifications and Test Procedures for Carbon Monoxide Continuous Emission Monitoring Systems in Stationary Sources."
- 40 CFR Part 60, Appendix F, "Quality Assurance Procedures."

VI. AIR QUALITY IMPACT ANALYSIS

General

The SRP facility is located in an area that has been designated as attainment or unclassifiable for all criteria pollutants; therefore, the pertinent requirements for ambient air quality impact analyses and other impact analyses are found in A.A.C. R18-2-406.A.5 and R18-2-407. The air quality analyses must demonstrate that the project's proposed significant emission increases will not cause or contribute to an exceedance of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. As noted in Section II of this Technical Support Document, CO, sulfuric acid mist and PM_{10} are emitted in quantities that exceed the PSD significant annual emission threshold.

Additional analyses required under A.A.C. R18-2-407 include an analysis of the impairment to visibility, soils, and vegetation, and an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the new source or modification. These analyses do not apply to the carbon monoxide since there is no growth associated with the proposed low-NO_x burner project and no known facts that indicate that CO emissions would lead to the impairment to visibility, soil and vegetation.

The CGS facility is located 55 kilometers (km) from the Petrified Forest National Park Class I area. A Class I area analysis was conducted and supplied to the Federal Land Manager for review. The project did not predict any adverse impacts on visibility and other Air Quality Related Values.

Modeling Analysis Design

EPA guidance for performing air quality modeling analyses is set forth in Chapter C of EPA's New Source Review Workshop Manual, Draft- October 1990, and in EPA's "Guideline on Air Quality Models", 40 CFR Part 51, Appendix W. ADEQ modeling guidance is contained in the ADEQ Modeling Guidelines. All modeling procedures used for the CGS analysis are consistent with relevant EPA and ADEQ guidance. The AERMOD (version 07026) dispersion model was used for the assessment of the ambient air impacts. This is the current EPA and ADEQ approved model for PSD modeling analyses. Outlined in the following are the results of the modeling. For detailed discussion such as meteorological data, receptor network, source locations and parameters, and building downwash, please review the submitted permit application package.

Modeling Results

The modeling analysis was conducted in two steps: a significant impact analysis, followed if necessary by a cumulative NAAQS and PSD increment analysis. Table 8 presents the summary of the significant impact modeling. The highest modeled short-term concentrations were tabulated for comparison to the significant impact level (SIL). The project's ambient impacts are greater than the SIL for all averaging intervals for CO and PM_{10}. Therefore, a cumulative NAAQS analysis was required. In addition, a PSD Increment analysis for PM_{10} was conducted. Maximum predicted impacts are less than all the NAAQS, as shown in Table 9. The maximum predicted impacts are less than the PM_{10} PSD Increment, as shown in Table 10.

Table 8: <u>Significant Impacts Analysis Results</u>

Average Period	Maximum Modeled Impact (μg/m^3)	SIL (μg/m^3)	Cumulative analysis? (yes/no)
24-hour PM_{10}	9.48	5	Yes
Annual PM_{10}	1.17	1	Yes
1-hour CO	5,344	2,000	Yes
8-hour CO	1,355	500	Yes

Table 9: <u>Summary of NAAQS Modeling for all Pollutants</u>

Average Period	Maximum Modeled Impact (μg/m³)	Background Concentration (μg/m³)	Nearby Background Sources (μg/m³)	Total Estimated Impact (μg/m³)	NAAQS (μg/m³)
3-hour SO_2	864.89	29.0	-	893.89	1,300
24-hour SO_2	98.39	16.0	-	114.39	365
Annual SO_2	5.50	3.0	-	8.50	80
Annual NO_2	5.58	2.4	-	7.98	100
1-hour CO	5,432	2,529	0.003	7,960	40,000
8-hour CO	1,229	1,609	0.29	2,839	10,000
Quarterly Pb	0.00021	0.03	-	0.03021	1.5
24-hour PM_{10}	58.42	51.3	0.11	109.86	150
Annual PM_{10}	14.08	10.6	0.08	24.72	50

Table 10: <u>Summary of PSD Modeling for PM_{10}</u>

Average Period	Maximum Modeled Impact (μg/m³)	Nearby Background Sources (μg/m³)	Total Estimated Impact (μg/m³)	PSD Increment (μg/m³)
24-hour PM_{10}	8.77	0.03	8.80	30
Annual PM_{10}	1.17	0.07	1.24	17

VII. REVISIONS TO CURRENT PERMITS AND CONDITIONS

CLASS I, TITLE V OPERATING PERMIT NO. 30732

A Title V operating permit was issued to SRP on November 21, 2005 for operation of the CGS coal-fired steam electric generating units. The following table lists permit references that are being revised due to source modifications and upgrades of permit #30732.

Condition #	Determination					Comments
	Keep	Revise	Add	Delete	Stream-line	

Condition #	Determination					Comments
	Keep	Revise	Add	Delete	Stream-line	
Attachment A	X					Attachment A General Provisions
Attachment B						
I.	X					This condition is for facility-wide requirements.
II.A		X				This condition contains the applicability statement and has been revised to include a definition for Unit Operating Day.
II.B		X				This condition for operating limitations is revised by adding requirements for FGD systems.
II.C.1		X				This condition for PM and opacity is revised for adding PM emission limits for each unit.
II.C.2		X				This condition for Air Pollution Control Requirements is revised by adding requirements for quality assurance.
II.C.3		X				This condition for Monitoring, Recordkeeping, and Reporting Requirements is revised by adding requirements of PM CEMS and CAM for PM.
II.C.4		X				This condition for Testing Requirements is revised for performance testing of PM.
II.C.5		X				This condition for Permit Shield is revised for adding EPA Consent Decree references.
II.D.1		X				This condition for NO_x emission limit is revised by adding emission limits arising out of the installation of low-NO_x burners on Unit 1 and 2 and SCR on Unit 2.
II.D.2		X				This condition for Air Pollution Control Requirements is revised by adding requirements for low-NO_x burners and SCR
II.D.3		X				This condition for Monitoring, Recordkeeping, and Reporting Requirements revised by adding methodology for monitoring of NO_x emission rate.
II.D.4		X				This condition for Permit Shield is revised for adding EPA Consent Decree references.
II.E	X					This condition is for carbon dioxide.
II.F.1		X				This condition for SO_2 emission limit is revised by adding emission limits arising out of the installation of FGD system on Unit 1 and 2.
II.F.2		X				This condition for Air Pollution Control Requirements is revised by adding requirements for FGD on Unit 1 and 2.

Condition #	Determination					Comments
	Keep	Revise	Add	Delete	Stream-line	
II.F.3		X				This condition for Monitoring, Recordkeeping, and Reporting Requirements is revised by adding methodology of monitoring of SO_2 emission rate, determining the SO_2 removal efficiency, and determining the SO_2 emission rate.
II.F.4		X				This condition for Permit Shield is revised for adding EPA Consent Decree references.
II.G			X			This new condition is for CO emission limitation, monitoring, recordkeeping, and report keeping requirements.
II.H			X			This new condition is for sulfuric acid mist emission limitation and testing requirements.
II.I			X			This new condition is for SO_2 allowance surrender requirements.
III	X					This condition is for the requirements for auxiliary boiler.
IV	X					This condition is for the requirements for internal combustion engines.
V		X				This condition is for the requirements for coal handling and the condition for opacity is revised with the new opacity limit.
VI		X				This condition is for the requirements for lime handling and the condition for opacity is revised with the new opacity limit. New conditions for equipment subject to New Source Performance Standards have been added.
VII		X				This condition is for the requirements for fly ash handling and the condition for opacity is revised with the new opacity limit.
VIII		X				This condition is for the requirements for cooling towers and the condition for opacity is revised with the new opacity limit.
IX	X					This condition is for the requirements for used oil specifications.
X	X					This condition is for the requirements for fugitive emissions.
XI	X					This condition is for the requirements for other periodic activities.
XII			X			This new condition is for the alternate operating scenario dry bottom ash handling system emission limitations and monitoring, recordkeeping, and reporting requirements.

VIII. NEW INSIGNIFICANT ACTIVITIES

The following table includes a list of new activities proposed by SRP Coronado to be insignificant. This table includes an evaluation of whether the activity can be deemed as insignificant pursuant to A.A.C. R18-2-101.57.

The following activities were proposed to be insignificant in the permit application (activities in redline format are being evaluated for significance):

S. No.	Activity	Insignificant	Comment
1	5,000 gallon sulfuric acid storage tank	Yes	No applicable requirement

IX. LIST OF ABBREVIATIONS

A.A.C. .... Arizona Administrative Code
ADEQ.......... Arizona Department of Environmental Quality
AERMOD.......... Air Dispersion Model
MM Btu/hr .... Million British Thermal Units per hour
BACT.......... Best Available Control Technology
CAS.......... Combustion Air Systems
CECP.......... Coronado Emissions Control Project
CEMS.......... Continuous Emission Monitoring Systems
CFR.......... Code of Federal Regulations
CGS.......... Coronado Generating Station
CO.......... Carbon Monoxide
COHPAC.......... Compact Hybrid Particulate Collector
CS-ESP.......... Cold Side Electro Static Precipitator
EPA .... Environmental Protection Agency
ESP.......... Electrostatic Precipitators
FF.......... Fabric Filter
FGD.......... Flue Gas Desulphurization
^{o}F.......... Degree Fahrenheit
GCP.......... Good Combustion Practices
H_2SO_4.......... Sulfuric Acid
HAP.......... Hazardous Air Pollutant
HS-ESP .... Hot Side Electro Static Precipitator
lb/hr .... Pound per Hour
LEAR .... Lowest Achievable Emission Rate
LNB.......... Low NO_x Burners
LOI.......... Loss on Ignition
NAAQS.......... National Ambient Air Quality Standard
NNSR.......... Non-attainment New Source Review
NO_x .... Nitrogen Oxides
PM .... Particulate Matter
PM_{10}.......... Particulate Matter Nominally less than 10 Micrometers
PRB.......... Powder River Basin
PSD .... Prevention of Significant Deterioration
PTE .... Potential to Emit or Permanent Total Enclosure
RACT .... Reasonably Available Control Technology
RBLC .... RACT/BACT/LAER Clearinghouse
SAM.......... Sulfuric Acid Mist
SCR.......... Selective Catalytic Reduction
SIL.......... Significant Impact Level
SO_2.......... Sulfur Dioxide
SRP .... Salt River Project
WESP.......... Wet electrostatic precipitation
VOC.......... Volatile Organic Compound